FERC decision on transmission access helps NU/PSNH merger

HARTFORD, CT—Progress was made recently on the Northeast Utilities/Public Service Co. of New Hampshire merger deal when the Federal Energy Regulatory Commission (FERC) approved an amended decision on the proposed merger. The amended decision modifies transmission-access conditions that FERC had attached to its approval of the merger (see *EL&P* 2/92, p.11).

Customers held harmless

As a result of the decision, NU and PSNH customers will be held harmless if other utilities and power producers in the Northeast need to use the NU/PSNH transmission system to buy or sell electricity, explained William B. Ellis, NU chairman and chief executive officer.

"While this decision does not make all the changes we requested last summer, it apparently does address the critical issue—transmission access—in a manner that treats NU and PSNH customers fairly. It is important to note that the work by the states of New Hampshire and Connecticut was critical in convincing the FERC commissioners to make the necessary changes to assure protection of ratepayers in those states.

Push ahead

"Based on our initial reading of the amended decision, we believe this decision should allow us to push ahead promptly with the remaining steps necessary to complete a merger that is nearly four years in the making," Ellis stated.

Under the merger plan, NU would acquire PSNH's 35.6-percent share of the Seabrook nuclear power plant and become managing agent responsible for operating Seabrook. NU said the deal would save PSNH and its customers an estimated $600 million over its lifetime and save NU and customers in Connecticut and Massachusetts $350 million.

New plants were small in 1991, no nuclear

WASHINGTON—In 1991, for the first time since 1967, no new nuclear plants went into operation, according to a recent Utility Data Institute (UDI) report.

UDI's latest edition of "Projected Capital Costs: U.S. Power Plants" found that of the 39 new power plants that did enter service last year, the average unit size was quite small. UDI statistics show a 76-percent decrease in average unit size over the past five years, from 574 MW in 1986 to 139 MW in 1991.

New capacity in 1991 totalled 5435 MW. A breakdown of total new capacity showed: coal-fired, 2989 MW; gas-fired, 1003 MW; hydroelectric, 1146 MW; and oil-fired 297 MW.

Planned capacity

UDI also reported that 47,188 MW of new utility generating capacity is scheduled for service between 1991 and 2000. Planned capacity includes: 10,298 MW now under construction; 5712 MW tied up in delayed coal and nuclear units; and 25,739 MW of capacity planned and in design.

U.S. nuclear units still under construction include Comanche Peak-2, scheduled for completion in 1993, and Watts Bar 1 & 2, expected to begin service before 2000.

Electric Utilities at a Glance

	Total Electric Utility Industry	Investor-Owned Utilities	Municipals	Cooperatives	State Projects, Public Power Districts	Federal Power Marketing Agencies
Installed Generating Capacity (kW in thousands)	735,051	568,769	40,115	26,337	34,397	65,434
% of Total	**100**	**77**	**5**	**4**	**5**	**9**
Generation (kWh in Millions)	2,807,058	2,201,007	97,670	126,115	146,994	235,272
% of Total	**100**	**78**	**4**	**5**	**5**	**8**
Customers (at December 31st)	109,958,503	84,228,417	12,764,526	10,846,117	2,092,189	27,254
% of Total	**100**	**77**	**12**	**10**	**2**	**>1**
Energy sales (kWh in thousands)	2,673,596,479	2,060,673,455	294,831,533	184,783,173	78,466,423	54,841,895
% of Total	**100**	**77**	**11**	**7**	**3**	**2**
Revenue (Thousands of Dollars)	$175,919,698	$139,447,850	$18,071,621	$12,766,462	$3,953,237	$1,680,528
Average Revenue per kWh from Total Sales	--	6.77¢	6.13¢	6.91¢	5.04¢	3.06¢
Average Revenue per kWh from Residential Sales	--	8.17¢	6.48¢	7.51¢	5.96¢	5.71¢
Number of Electric Generating Plants	3,437	1,988	1,049 (a)	215	(a)	185

Note: Total may not equal sum of components due to independent rounding.
(a) Breakdown of Municipals, State Projects and Public Power Districts data not available, only total for Publicly-Owned Electric Utilities is shown.
Figures are preliminary 1990, except for Installed Generating Capacity and Number of Electric Generating Plants which represent final data.
Source: EEI, "1990 Statistics Non-Investor Owned Utilities," December 1991.

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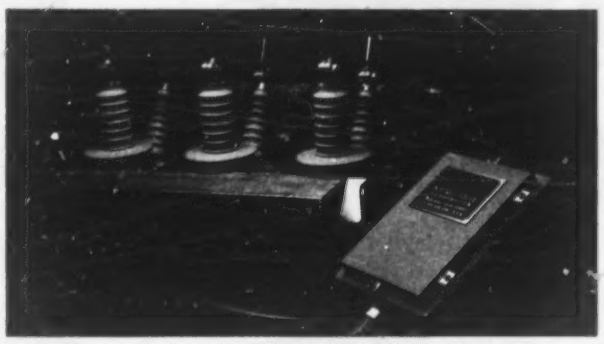

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Inquire R.S. 6

HENRY STEIN, Senior Editor-Power Production

Thermal energy storage improves combustion turbine operation

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Thermal energy storage (TES) inlet air cooling is a new concept that is an economical, feasible method for increasing the peak capacity rating of combustion turbines. The benefits of a short design/construction schedule and added capacity at a low cost per kilowatt make it an attractive option to utilities approaching their peak capacity.

Most combustion turbines are used for peaking duty during the summer months when residential and commercial cooling loads are the greatest. Ironically, this same hot weather sharply lowers the turbines' capacity ratings. In other words, a utility buys seriously derated capacity when it installs such a turbine for peaking service.

However, cooling the ambient air before it enters the bell mouth of the combustion turbine allows the peak rated capacity of the machine to be used when it is needed most.

Current application

TES technology for combustion turbine inlet air cooling is being applied by Lincoln Electric System, Lincoln, NE. System operation began in September 1991 at the utility's Rokeby Station, as a retrofit to an existing General Electric Frame 7B peaking unit with an evaporative cooler rated at 65 MW at 100°F. The inlet cooling was expected to increase the turbine's capacity by 25 percent.

The Rokeby TES system is the largest of its kind in the U.S. and the first application of ice harvesting for inlet air cooling.

The combustion turbine had been installed in 1975. The TES addition cost a little over $2 million and added 11 MW to the 100°F capacity. In addition, redesigned inlet guide vanes cost about another $160,000 and added an extra 2 MW to the turbine's capacity, and converting from oil burning to gas burning cost $400,000 and added another 1 MW. The entire project took less than a year.

The system's ice tank holds 1.1-million gal of ice and chilled water (at about a 9:1 ice-to-water ratio). If final results this summer match preliminary tests, Lincoln Electric plans to include chillers with all combustion turbines it installs in the future.

Burns & McDonnell provided detailed design and procurement; the Electric Power Research Institute and the American Public Power Association provided partial funding.

Inlet air cooling primer

A combustion turbine is a mass flow machine—greater air mass flow through it creates higher generating capacity within its design limits. As air temperature decreases, it becomes more dense, and a compressor with a fixed volume flow rate can move more air mass than at warmer temperatures—the compressor's capacity and efficiency increase at lower temperatures.

Thus capacity, heat rate, fuel flow, exhaust temperature, and efficiency are all related to combustion airflow ambient temperature (see figure). The most significant benefits to inlet air cooling include:

- *Increased capacity*—The greatest benefit is to increase unit electrical generating capacity during periods of high ambient temperatures. Manufacturer's performance curves indicate up to a 24-percent increase in capacity on a 100°F day. For example, on a GE frame 7EA, the increased capacity equates to approximately 17 MW at 40°F over the 100°F rating of 73 MW.
- *Improved efficiency*—Inlet air cooling increases system efficiency by operating the turbine at a lower heat rate at lower ambient temperatures. Manufacturers' performance curves predict that unit heat rate decreases by approximately 4 percent between 100°F and 40°F.

Fuel cost savings from the efficiency gain can offset the operating cost of running the TES refrigeration system on offpeak energy. This estimate is a utility-specific parameter that depends on the cost of fuel and offpeak energy.

- *Life extension*—Since the combustion turbine runs cooler with TES, its components' lives are extended. However, no quantitative estimates are yet available concerning life extension or maintenance cost savings due to inlet air cooling.
- *Delayed new generation*—By adding inlet air cooling to existing combustion turbines, the resulting capacity increase may be enough to delay the installation or purchase of new capacity for one or more years.
- *More efficient use of baseload capacity*—TES inlet air cooling produces ice during offpeak hours on economical power. The resulting increase in baseload capacity factor also provides better management of a utility's baseload capacity and perhaps a slight improvement in overall system efficiency.

Ice harvesting system

Several approaches can be used in design of a TES system, one of which is "ice harvesting," as used at Rokeby, in which a refrigeration system produces ice that then is stored in a tank until used to cool the inlet air. The three basic ice-harvesting cycles are daily, weekly, and yearly. Each cycle's best applications depend on combustion turbine operation and site-specific economics:

- *Daily*—This cycle produces the required quantity of stored ice every day. A TES system for a baseload combustion turbine requires a daily cycle. Another application is where the cost of energy does not vary throughout the day and week, and the cost of the refrigeration system can be balanced against that of a larger ice storage tank.

The equipment required includes a small ice storage tank and large refrigeration system.

- *Weekly*—A weekly cycle produces enough ice to balance the weekly thermal cooling requirements of the combustion air. The cycle is ideal for a combustion turbine operation that requires peaking capacity a few hours a day, for five or fewer days per week.

Operating a weekly cycle requires a moderately sized ice storage tank and refrigeration system.

- *Yearly*—A yearly TES cycle produces ice continuously to provide the total yearly combustion air cooling requirements. It is used when rare, short-duration peaking requires reserve capacity and/or when energy cost is high continuously.

Yearly cycle requirements include a large ice storage tank and small refrigeration system. A yearly cycle would not be economical for most utilities.

Short leadtime

A TES inlet air cooling facility can be designed, procured, installed, and operational in less than one year, as proven out at Rokeby Station. Currently, the longest lead-time item to manufacture is the large, high-voltage (4160-V) motors for the refrigeration compressor and the circulating water pumps. These units may require up to 20 weeks from release to manufacturer to job site delivery.

However, the ice storage tank takes the longest to construct. Depending on construction methods, it may take up to three months after contractor mobilization to excavate, construct, and test the tank.

Cost of a TES inlet air cooling facility depends on:

- *TES cycle*—A daily cycle requires a smaller ice storage tank, but larger refrigeration system and higher operating cost than a weekly cycle.
- *Ambient conditions*—As wet and dry bulb design temperatures increase, so does the required size of the ice storage tank, inlet air cooling heat exchanger, circulating water system, and refrigeration system.
- *Site-specific conditions*—Retrofit of TES inlet air cooling onto an existing plant site with limited land availability is more expensive than designing it for a new site with a new combustion turbine.
- *System control and monitoring*—A simple on/off operation is less expensive than full programmable logic controls with system monitoring and reporting.
- *Construction quality*—Utility-grade quality materials and construction are more costly than comparable commercial- or industrial-grade.

A complete TES inlet air cooling facility based on a weekly TES cycle, 100°F dry bulb, 70°F wet bulb, existing combustion turbine site, computer-controlled, of utility-grade quality can be installed for approximately $200/kW. This estimate is based on a GE frame 7EA unit and should only be used for initial economic feasibility purposes.

Economics

Peak electrical generating capacity is normally only used a short period of time each year (1000 hr or less), or as unused reserve capacity. But peak generating capacity does not need to provide economical electrical energy. The lowest initial-capital-cost capacity is usually installed for peaking duty, with less concern given to variable operating costs.

The simplest comparison is between the incremental installed cost of a TES system and other forms of new or purchased peaking capacity. Based on this type of evaluation, the estimated break-even period is between two and three years.

Even with the improved efficiency inlet cooling brings to a combustion turbine, the total system net heat rate increases by approximately 4 percent. This is a result of the energy requirements of the TES refrigeration and circulating water.

However, the total system variable operating cost per kilowatt of a TES inlet air cooling/combustion turbine system is, in most cases, equal to or only slightly higher than (less than 1 mill/kWh) a simple-cycle combustion turbine without inlet cooling. This is because high-priced peaking fuel (natural gas or fuel oil) can be replaced with lower-priced, base-capacity fuels such as coal or nuclear.